Progress Report

Task 1: Review existing methodologies to assess SG

Task 2: Developing a comprehensive methodology

Existing Methodologies Review

- Focus is on the benefits side of the benefits-cost equation
- Prior art is Itron's
- Itron's approach partly based on an E3 methodology (E3M)
- E3M was developed for planning energy efficiency programs
- Numerous suggestions to apply E3M to other investments
- Distributed generation (DG) was included (➔SG)
- Focus review on suitability of E3-like approach for SG
- Further focus on estimating energy & T&D-related benefits

Suitability of the E3 Methodology for Assessing Self-Generation

- **E3M intended for planning energy efficiency investments**
- **Suggestions to extend the E3M to other programs**
- **Economic efficiency/equity considerations require:**
  - **Methodological consistency/uniformity across all programs**
  - **The suitability question is therefore pertinent**

Positive Attributes of the E3M

- Simplicity
- Transparency

Issues

- Disconnect from the realities of the marketplace
- Key transmission benefits excluded
- Claimed transmission benefits are tenuous at best
- Lack of locational specificity of T&D benefits
- No valuation of on-site reliability support

Task 2 Progress

A 5-Step Approach:

- Identifying SG benefits and costs
- Define SGIP evaluation requirements
- Retrospective Assessment Methodology (RAM)
- Prospective Assessment Methodology (PAM)
- Integrating the assessments

SGIP Benefits & Costs Matrix

Participant	Non-Participant	California
Benefits		
Electric bill savings	Avoided energy costs	Customer reliability benefit
Customer reliability benefit	Energy commodity savings	Local reliability benefits
Cutomer enviromental credits	Congestion charge savings	Cutomer enviromental credits
Fuel-for-heat savings	Transmission losses savings	Societal enviromental benefits
Tax credits	Avoided ancillary services charges	Fuel-for-heat savings
	Avoided CAISO charges	Avoided energy costs
	Congestion reduction savings	Avoided ancillary services charges
	Customer standby fees	Avoided CAISO charges
	Distribution capital deferral savings	Congestion reduction savings
	Distribution loss savings	Distribution capital deferral savings
	Local reliability benefits	Distribution loss savings
		Gas-price moderation savings
		Present value of Direct Benefits
Present value of customer benefits		Indirect Economic Benefits
Present value of all customers benefits	Present value of all benefits	Present value of all benefits
Costs		
SG Fuel costs	Lost revenues	SG Fuel costs
SG O&M expenses	SGIP administrative costs	SG O&M expenses
SG Capital costs		SG Capital costs
Standby charges		SGIP administrative costs
Present value of customer costs		
Present value of all customer costs	Present value of all costs	Present value of all costs
Net Present Value (NPV)		
NPV for customer		
NPV for all customers	NPV for all non-participants	NPV for California

Participant(s) Benefits & Costs Matrix

Benefits	Costs
Electric bill savings	SG Fuel costs
Customer reliability benefit	SG O&M expenses
Cutomer enviromental credits	SG Capital costs
Fuel-for-heat savings	Standby charges
Tax credits	
Present value of customer benefits	Present value of customer costs
Present value of all customers benefits	Present value of all customer costs
Net Present Value (NPV)	
NPV for customer	
NPV for all customers (Participants)	

Non-Participants Benefits & Costs Matrix

Benefits	Costs
Avoided energy costs	Lost revenues
Energy commodity savings	SGIP administrative costs
Congestion charge savings	
Transmission losses savings	
Avoided ancillary services charges	
Avoided CAISO charges	
Congestion reduction savings	
Customer standby fees	
Distribution capital deferral savings	
Distribution loss savings	
Local reliability benefits	
Present value of all benefits	Present value of all costs
Net Present Value (NPV)	

California’s Benefits & Costs Matrix

Benefits	Costs
Customer reliability benefit	SG Fuel costs
Local reliability benefits	SG O&M expenses
Cutomer enviromental credits	SG Capital costs
Societal enviromental benefits	SGIP administrative costs
Fuel-for-heat savings	
Avoided energy costs	
Avoided ancillary services charges	
Avoided CAISO charges	
Congestion reduction savings	
Distribution capital deferral savings	
Distribution loss savings	
Gas-price moderation savings	
Present value of Direct Benefits	
Indirect Economic Benefits	
Present value of all benefits	Present value of all costs
Net Present Value (NPV)	

Overview of California's Benefits

Benefits	$ Value	Likelihood	Valuation
Customer reliability benefit	High	Needs targeting	Doable
Local reliability benefits	Low-medium	Needs targeting	Difficult
Cutomer enviromental credits	High	High	Doable
Societal enviromental benefits	High	High	Difficult
Fuel-for-heat savings	High	If targeted	Easy
Avoided energy costs	Highest	Certain	Doable
Avoided ancillary services charges	Low	Certain	Easy
Avoided CAISO charges	Very low	Certain	Easy
Congestion reduction savings	High	Low	Doable
Distribution capital deferral savings	Variable	Needs targeting	Difficult
Distribution loss savings	Low	Certain	Doable
Gas-price moderation savings	Very low	Certain	Doable

SGIP Evaluation Requirements

1. **Capture market realities over entire service life of every SG**

2. **Seamless applicability across all markets & technology types**

3. **Conduct both retrospective & prospective assessments**

4. **Transparency without compromising (1) or (2)**

5. **Easily integratable with public data resources/planning tools**

6. **Amenable to utilization by all parties in California**

Market Realities

- Energy-commodity worth dominates
  - ❑ Exceptions: heat & power and on-site reliability applications
  - ❑ T&D benefits likely small except when locationally targeted
- Zonal energy commodity markets in transition since 2001
  - ❑ 2001–2003: Net shortage Procurement/scheduling for IOUs
  - ❑ 2004–Now: IOUs self-procure & schedule
- New market structure to arrive later this year

Market Realities (Continued)

- **A mix of regulated and unregulated market segments:**
  - **Utility resources**
  - **<u>Merchant generation</u>**
  - **<u>CAISO markets</u>**
- **Mix has been evolving since SGIP's start and continues to do**
  - **Zonal to nodal pricing regimes**
  - **Spot market → LT contracts →Resource Adequacy**
- **Need Integrated retrospective & prospective assessments**

Seamless Application

- **Energy commodity is the common denominator tying SG with:**
  - **DG**
  - **Energy efficiency**
  - **QFs**
  - **Bulk power markets**
- **Economic efficiency/equity require same valuation techniques**
- **Non-energy benefits can vary as add-ons**
- **Need Integrated retrospective & prospective assessments**

Need for Both Retrospective & Prospective Assessments

- Investments of interest initiated in 2002 - 2007
- SG service life spans 10-20 years
- Program evaluation must cover past and future performances
  - Retrospective assessment to cover 2002 – 2008
  - Prospective assessment to cover 2009 – 2026
- Present value method to integrate results into NPV estimates

Retrospective Assessment Methodology Considerations

- **Investments incurred: 2002 – 2007**
- **Established market realities**
- **Identified benefits**
- **Measurable benefits**
- **The Retrospective Assessment Methodology**

<u>Established</u> Market Realities

- **Energy commodity worth particularly dominant (up to 90% +)**
- **Zonal energy commodity markets in transition since 2001**
  - ❑ **2001: CAISO/DWR procurement/scheduling for IOUs**
  - ✓ **2001—2003: DWR procurement/scheduling for IOUs**
  - ✓ **2004–Now: IOUs self-procure & schedule**

The Retrospective Assessment

Identified Benefits

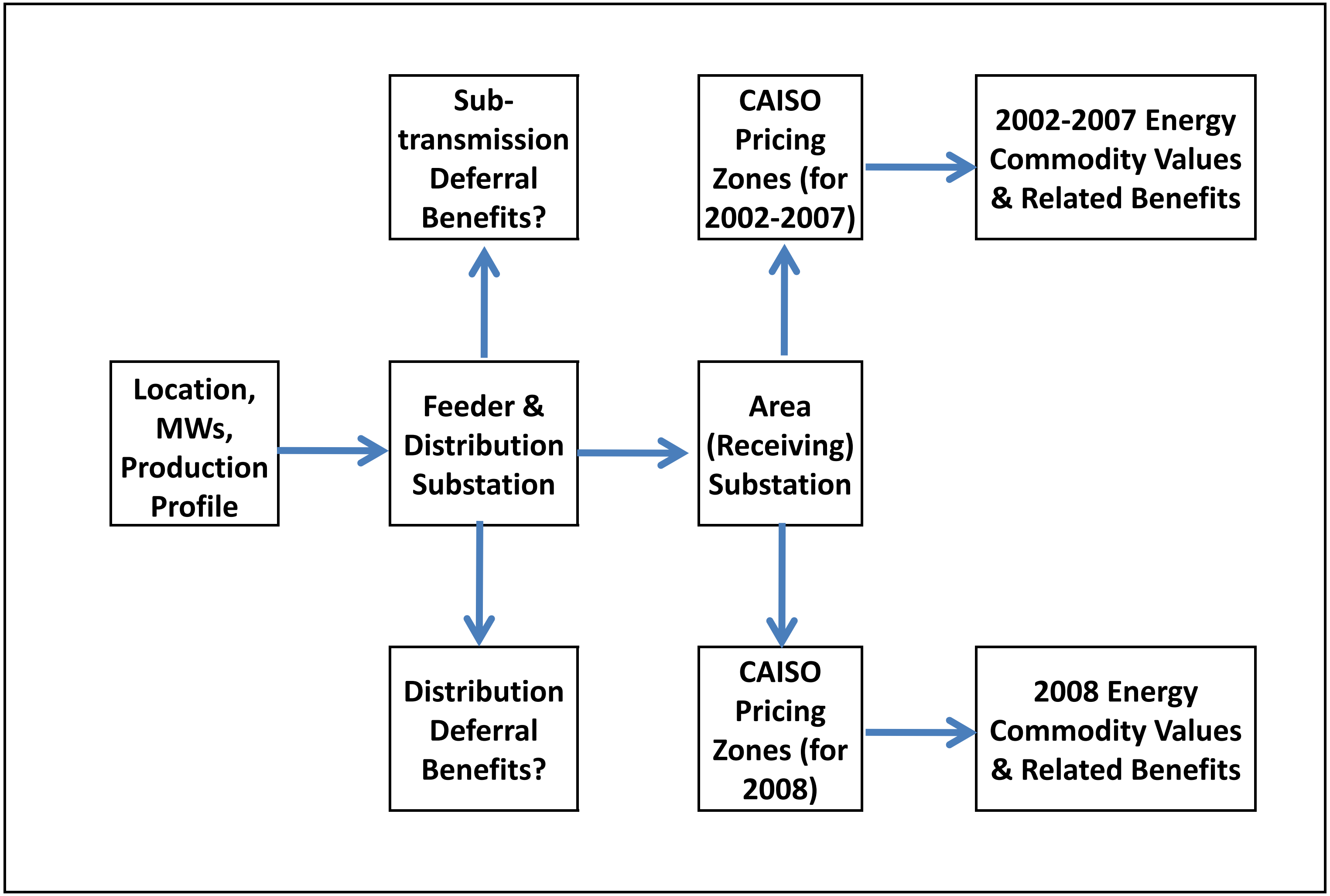
- Energy-related savings
  - ❑ CAISO-delivered energy savings
  - ❑ Congestion cost reduction
  - ❑ Ancillary service cost reduction
  - ❑ Reduced delivery losses
  - ❑ Gas price moderation
- T&D upgrading cost reduction:
  - ❑ Transmission deferral (claimed)
  - ❑ Distribution deferral

The Retrospective Assessment

Measurable Benefits

- Energy-related savings
  - ✓ Procured-energy savings
  - ✓ Congestion cost reduction
  - ✓ Ancillary service cost reduction
  - ❑ Reduced delivery losses – Only distribution-level losses
  - ❑ Gas price moderation – Too small to measure
- T&D upgrading cost reduction:
  - ❑ Transmission deferral – Virtually impossible
  - ✓ Distribution deferral (including subtransmission)

The Retrospective Methodology From Location To Benefits



The Retrospective Assessment

Energy-Related Savings

- Energy procurement: IOU vs. SG costs
- Congestion: Avoided by SG in congested zone
- Ancillary services: SG avoids CAISO costs
- Other avoided charges

Retrospective Assessment Methodology The Broad Picture for the Energy Commodity

2002 - 2008 Module

Use Costs of IOU-Specific, DWR-Scheduled Dispatchable Energy As Proxies for the Energy Commodity Values for SGIP Facilities	**Use Costs of IOU-Scheduled Dispatchable DWR Energy As Proxies for the Energy Commodity Values for SGIP Facilities**

The Retrospective Assessment

Distribution Deferral Savings

- SG location → Feeder & transformer identities
- Get feeder & transformer ratings & peak loads
- Determine if SG deferred or will defer upgrades
- Look for highly saturated, slow load-growth circuits

Prospective Assessment Methodology Considerations

- Investments incurred: 2002 – 2007
- Market realities
- Identified benefits
- Measurable benefits
- The Prospective Assessment Methodology

Prospective Assessment
Market Realities

- Energy-commodity worth expected to continue to dominate

- 2009 – 2026: Nodal (bus-specific) pricing takes over

The Retrospective Assessment

Identified Benefits

- Energy-related savings
  - ❑ CAISO-delivered energy savings
  - ❑ Congestion cost reduction
  - ❑ Ancillary service cost reduction
  - ❑ Other avoided charges
  - ❑ Reduced delivery losses
  - ❑ Gas price moderation
- T&D upgrading cost reduction:
  - ❑ Transmission deferral (claimed)
  - ❑ Distribution deferral

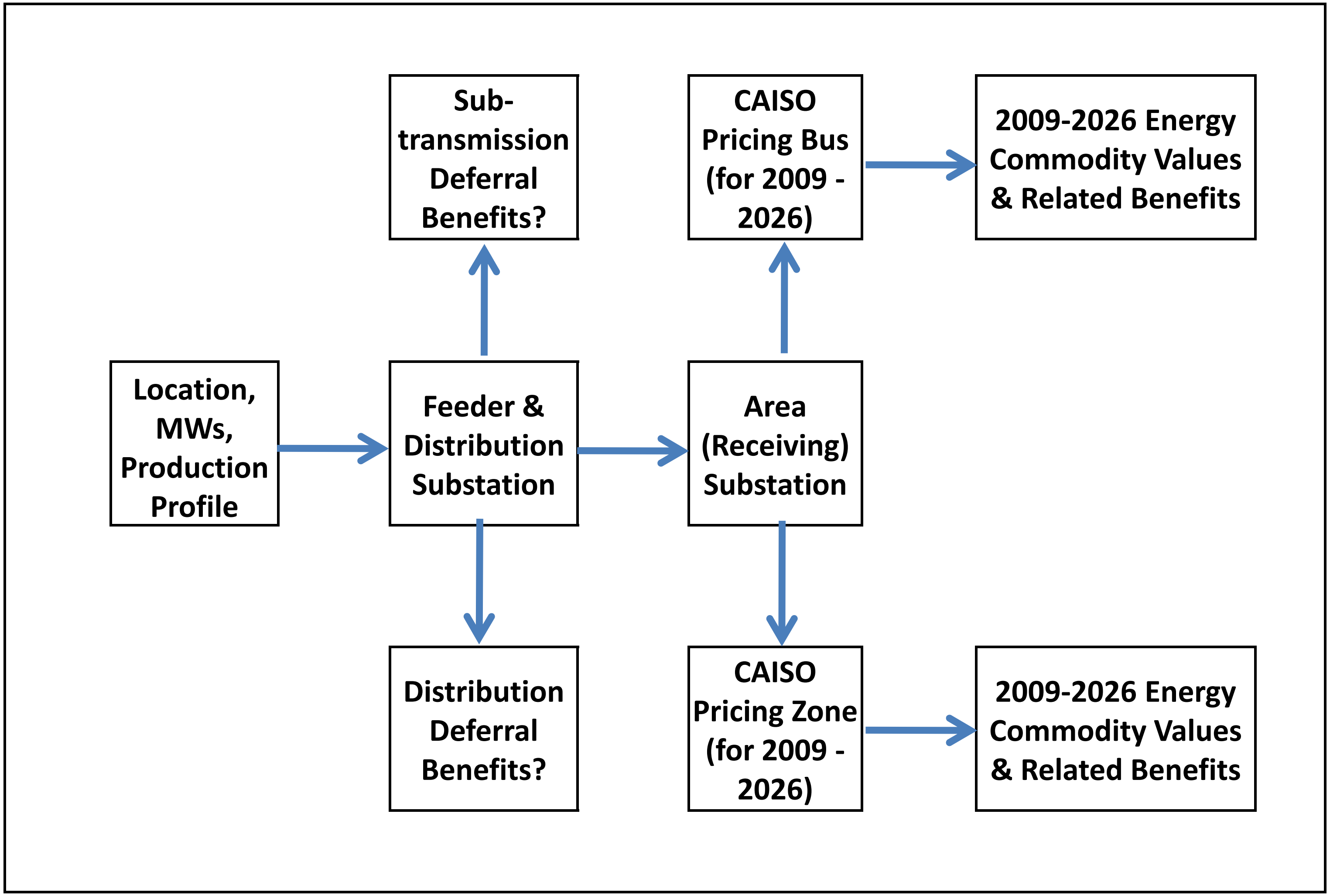
The Retrospective Assessment

Measurable Benefits

- **Energy-related savings**
  - ✓ **CAISO-delivered energy savings**
  - ✓ **Congestion cost reduction**
  - ✓ **Ancillary services & other CAISO cost reductions**
  - ❑ **Reduced delivery losses – Only distribution-level losses**
  - ❑ **Gas price moderation – Too small to measure**

- **T&D upgrading cost reduction:**
  - ❑ **Transmission deferral – Virtually impossible**
  - ✓ **Distribution deferral (including subtransmission)**

The Prospective Methodology From Location To Benefits



Prospective Assessment Methodology
The Broad Outlook for the Energy Commodity

2009 - 2026

Simulate Market Operation Using Security-Constrained Economic Dispatch (SCED) Models (e.g., GE's MAPS); Progressively Supplemented by CAISO-Posted Day-Ahead Nodal Prices & Numeric Extrapolation/Interpolation Techniques

Review of CAISO's Locational Marginal Pricing (LMP) Market Platform

- Compute/publish <u>bus-specific</u> (nodal) prices for Day-Ahead (DA), Hour-Ahead (HA) & Real-Time (RT) markets
- CAISO to use <u>nodal</u> prices to settle wholesale transactions
- Utilities' purchases to be settled at <u>zonal</u> prices derived from load-weighted bus-specific LMPs within each zone
- IOUs' congestion cost risks to be mitigated by entitling most loads with congestion revenue rights (CRRs)

What is Locational Marginal Pricing?

LMP equals the incremental cost to supply one more MW of load at a given bus/node using the lowest production cost of all available generation, while observing all transmission limits

Each nodal LMP consists of the following components:

- ✓ **System energy**
- ✓ **Transmission Congestion**
- ✓ **Marginal transmission losses**

How Will LMPs Be Calculated?

A Full Network Model (FNM) to be used to provide Locational Marginal Pricing – or “nodal” prices

- **LMP calculated for each bus or “node” on the grid**
- **Each node represents a place where energy is received from generation or delivered to customers**

- **CAISO to post hourly DA LMPs for ~ 3,000 buses**

How Will LMPs be used?

- Generators/suppliers paid <u>hourly LMPs</u> based on where they inject generation into the grid (<u>the injection bus)</u>

- IOUs to pay a <u>zonal LMP</u> equal to the average, load-weighted LMPs for all <u>take-out buses</u> within service area

Impact of Marginal Losses on LMPs

Marginal loss factors - twice as much as average loss factors.

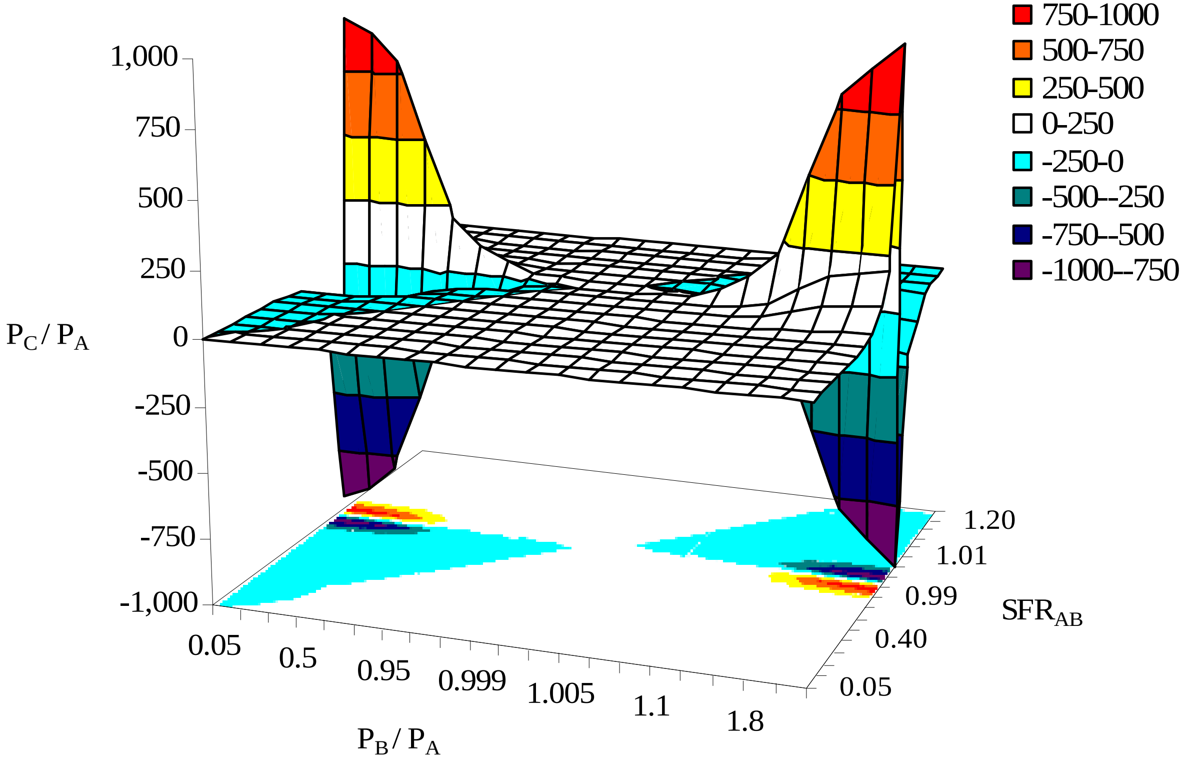
- ✓ Can radically alter the FNM dispatch decisions and even the direction of power flows on ties literally from one instant to the next.
- ✓ Absent transmission congestion, losses will be large enough to generate locational price differences between buses.
- ✓ Can interact synergistically with congestion to magnify locational nodal price differentials.
- ✓ Losses can't be hedged.

Spatial LMP Differentials (SLDs) Could Be Significant

Prospects for price dispersions:

- All 3 components of LMPs could contribute to high SLDs:
  - Large commodity bidding disparities in a hydrothermal system
  - Congestion costs due to real line loadings and/or ETC abuses
  - Marginal losses could be significant for long-distance transmission
- Even PJM exhibited high SLDs in spite of the fact that:
  - Unlike California, PJM is basically a thermal system;
  - ETCs do not play as significant a role as in California;
  - It is a much more meshed grid than California’s; and
  - Marginal losses were not used in PJM at that time

Nodal Price Sensitivity To Bid Prices & Generation Shift Factors

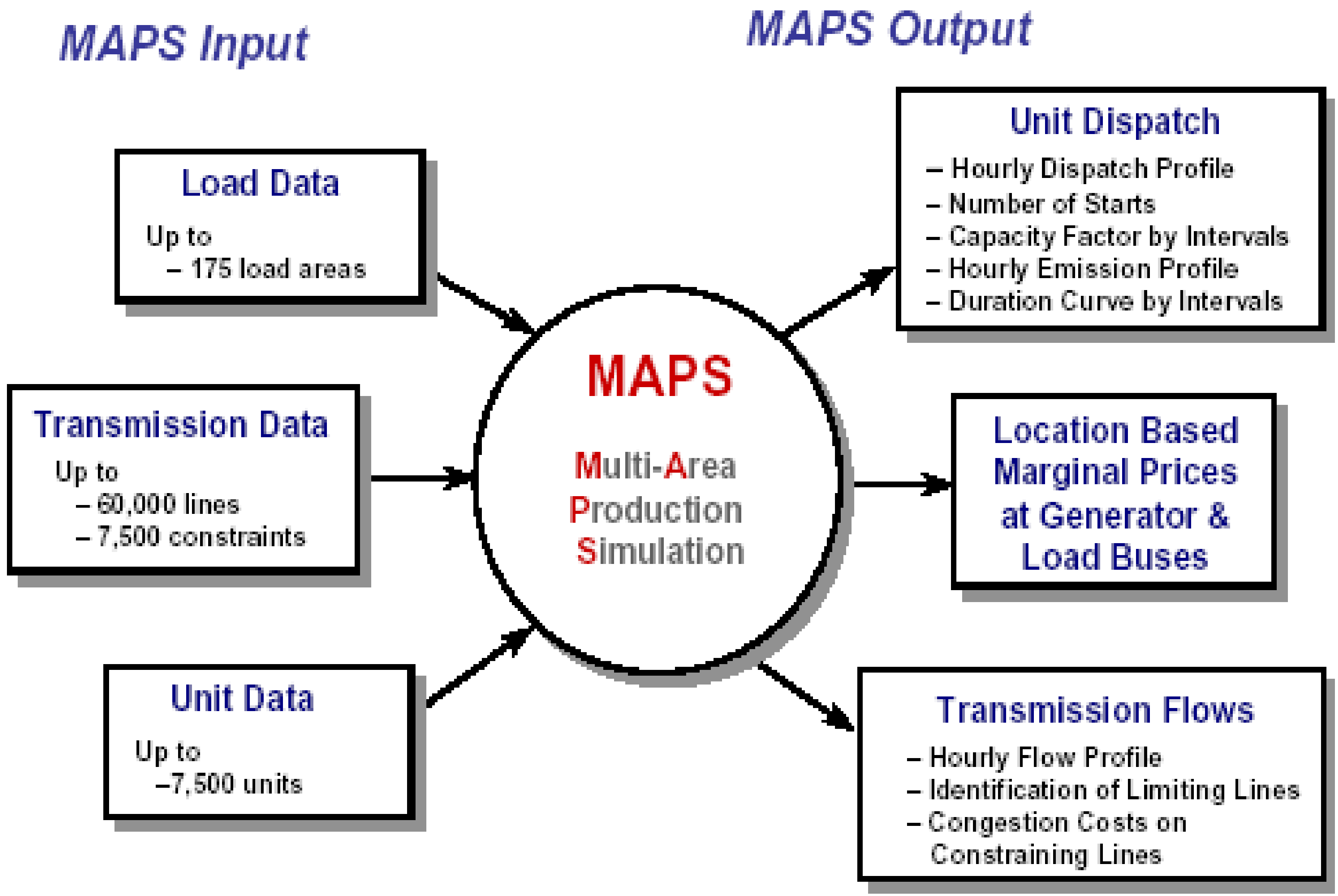


LMP Emulation Methodology

- SCUCD to emulate CAISO’s FNM: GE’s MAPS
- Assume full competition
- Exclude sporadic market stresses

GE MAPS

- ✓ Uses detailed representation of the WECC reliability region to perform commitment and dispatch of generation resources.
- ✓ Dispatch constrained to prevent over loading transmission lines beyond their normal (continuous) rating
- ✓ Computes transmission flows, congestion and nodal LMP prices for every hour


MAPS Input
MAPS Output
Load Data
Up to
– 175 load areas
Transmission Data
Up to
– 60,000 lines
– 7,500 constraints
Unit Data
Up to
–7,500 units
MAPS
Multi-Area
Production
Simulation
Unit Dispatch
– Hourly Dispatch Profile
– Number of Starts
– Capacity Factor by Intervals
– Hourly Emission Profile
– Duration Curve by Intervals
Location Based Marginal Prices at Generator & Load Buses
Transmission Flows
– Hourly Flow Profile
– Identification of Limiting Lines
– Congestion Costs on Constraining Lines

Using MAPS

- Focus on the California market
- Assume bidding at marginal costs
- Revamp the GE database
- Run simulation for study years
- Select a geographically representative set of generators
- Extract nodal prices at generator buses

MAPS Database

- Combination of load, generation, fuel pricing & transmission data
- Sources: RDI, WECC, CEC, EIA and FERC forms, GE, evolution, etc.
- Generating units data (e.g., outage & heat rate details)
- Fuel assumptions
- Normal hydro year
- Transmission: Based on WECC latest Base Case load-flow study

Methodology: The Full Competition Assumptions

- No California experience with nodal bidding
- Borrowing from other ISOs:
  - California’s uniqueness
  - Accessibility to commercially sensitive data
- Study objective is to evaluate SGIP benefits:
  - Exclude lack of competition
  - No market gaming

Methodology: Excluding Sporadic Market Stresses

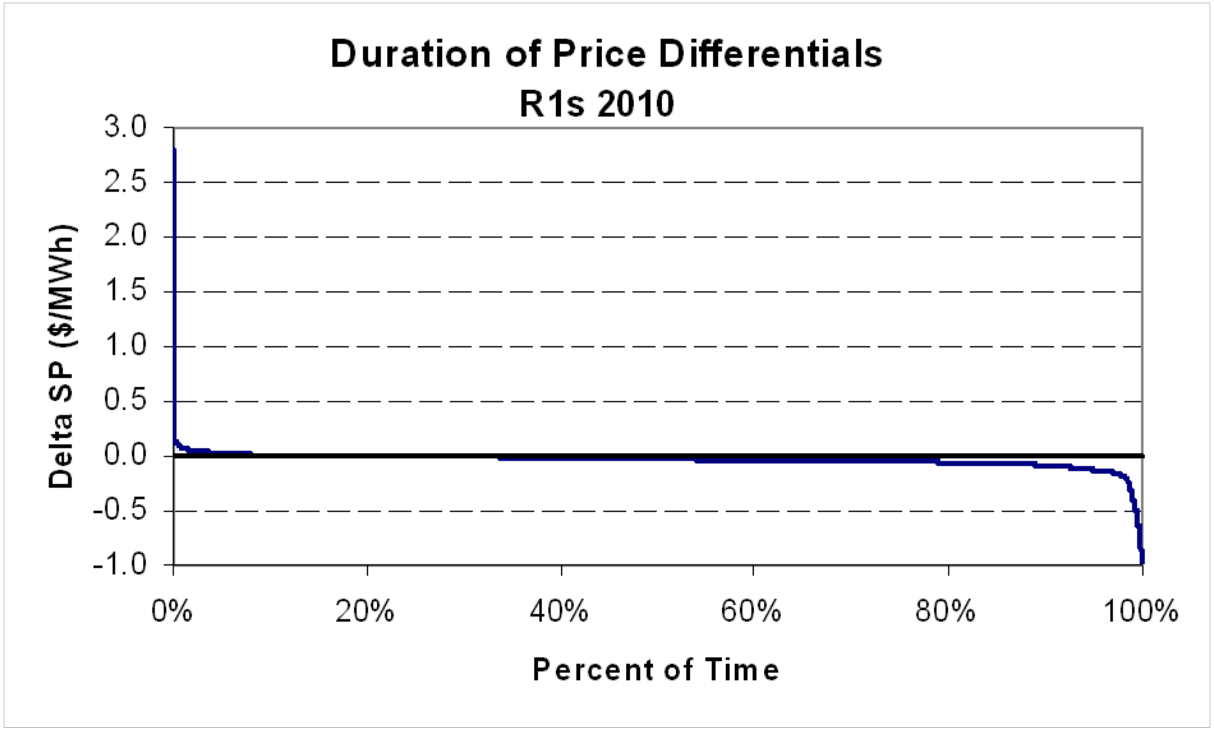
- **Rationale:**
  - **Focus on SGIP value under normal market conditions**
  - **Predictability of the effects of market stresses**
  - **Essential to data-management economy**
- **Excluded stresses:**
  - **Gas price spikes & sustained highs**
  - **Low hydro conditions**
  - **Prolonged G&T outages**
  - **Demand spikes & accelerated growth**

Price Differentials between San Francisco and Average Northern California ($/MWh)

Scenario: System Dispatch without marignal losses

Delta	2007	2008	2009	2010
Average	0.08	-0.06	-0.05	-0.04
Minimum	-0.82	-1.31	-1.39	-1.08
Maximum	1.61	0.17	0.23	2.79

Price Differentials between San Francisco and Average Northern California System Dispatch without Marginal Losses



Price Differentials between San Francisco and Average Northern California ($/MWh)

Scenario: System Dispatch with marignal losses

Delta	2007	2008	2009	2010
Average	4.41	4.62	4.98	5.19
Minimum	1.89	2.02	-0.11	-8.74
Maximum	11.39	9.38	9.79	10.06

Price Differentials between San Francisco and Average Northern California System Dispatch with Marginal Losses